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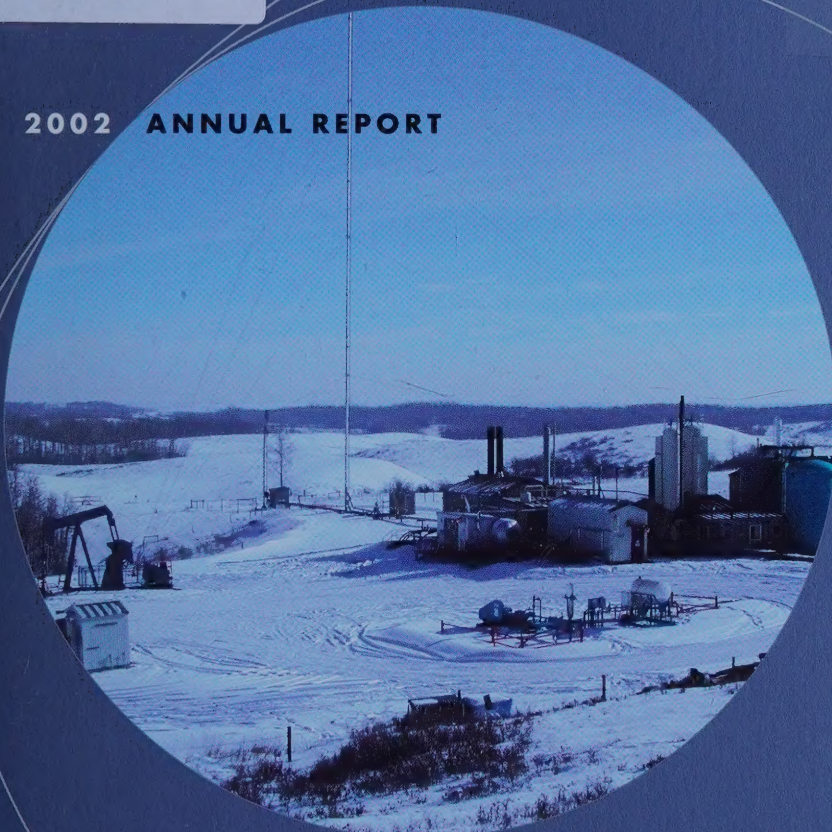
2002 ANNUAL REPORT



CASE RESOURCES INC.

Case Resources Inc. **2002 ANNUAL REPORT**

CONTENTS

Annual General Meeting

The Annual General Meeting of shareholders of the Corporation will be held on May 8, 2003 at 3:00pm in the Viking Room at the Calgary Petroleum Club, 319-5th Avenue S.W., Calgary, Alberta.

Cover photograph by Kelly Nichol, Operations Superintendent – Haynes Facilities looking southeast – February, 2003.

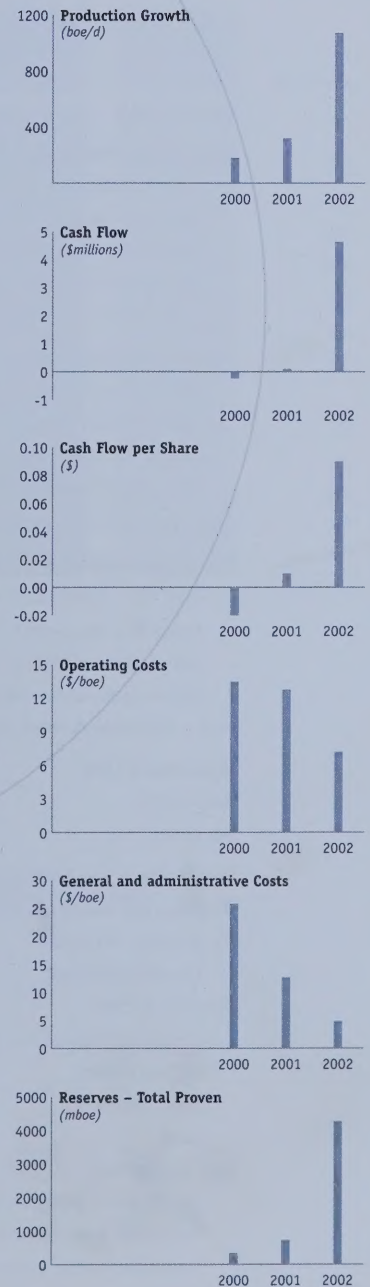
Case Resources Inc. is an aggressive oil and gas exploration development and production company based in Calgary, Alberta, whose assets are in western Canada. Case's management team was appointed in September 2000. The company has grown from an average of 322 boe/day in 2001 to 1,073 boe/day in 2002. Case averaged 1692 boe/day in the fourth quarter of 2002.

Directors, management, and their families own in excess of 35% of the outstanding shares of Case, which aligns their interests with those of other shareholders.

Case's strategy is to have clearly focused core production areas, with high working interests and operatorship. Case expects its properties to possess exploitation, development and exploration potential. Case prefers to own its infrastructure where possible.

We expect to aggressively purchase assets, or other corporate entities, in order to achieve these goals. As our cash flow grows we fully expect to develop a grass roots exploration program to augment our acquisition strategies.

Case trades on the TSX under the symbol **CAZ.**



	Year ended December 31 2002	Year ended December 31 2001	% Change
OPERATING			
Daily Average Production			
Light Oil – barrels	**532**	150	255
Heavy Oil - barrels	**348**	147	137
Natural Gas – thousands of cubic feet	**853**	138	518
Natural Gas Liquids – barrels	**51**	2	2,450
Total – barrels of oil equivalent (6:1)	**1,073**	322	233
Average Sales Price *($ Canadian)*			
Light Oil – per barrel	**39.34**	36.66	7
Heavy Oil – per barrel	**20.23**	22.23	(9)
Natural Gas – per thousand cubic feet	**4.49**	5.24	(14)
Natural Gas Liquids – per barrel	**31.82**	37.78	(16)
Total – per barrel of oil equivalent *(6:1)*	**31.14**	29.70	5
Proved and Probable Reserves *(before royalties)*			
Light Oil – thousands of barrels	**3,348**	206	1,525
Heavy Oil – thousands of barrels	**957**	816	17
Natural Gas – millions of cubic feet	**6,754**	182	3,611
Natural Gas Liquids – thousands of barrels	**467**	5	9,240
Total – thousands of barrels of oil equivalent *(6:1)*	**5,897**	1,057	458
Undeveloped Land			
Gross *(acres)*	**25,324**	18,007	41
Net *(acres)*	**8,728**	4,837	80
Unit Netbacks and Costs *($ per barrel of oil equivalents 6:1)*			
Petroleum and natural gas sales	**$ 31.34**	$ 29.78	5
Royalties, net of ARTC	**(6.76)**	(3.32)	104
Operating expenses	**(7.21)**	(12.77)	(44)
Operating netback	**17.37**	13.69	27
General and administrative expense	**(4.83)**	(12.67)	(62)
Interest expense	**(0.54)**	(0.18)	200
Other income	**0.02**	0.60	(97)
Taxes	**(0.14)**	(0.57)	(75)
Cash flow netback	**11.88**	0.87	1,266
Depletion and depreciation	**(6.61)**	(12.95)	(49)
Ceiling test write-down of P and NG properties	**–**	(75.76)	
Future income tax recovery	**1.37**	10.66	(87)
Income (loss) for the period	**$ 6.64**	$ (77.18)	

	Year ended December 31 2002	Year ended December 31 2001	% Change
FINANCIAL			
Petroleum and Natural Gas Sales *($)*	**12,272,209**	3,489,522	252
Cash Flow from Operations *($)*	**4,649,299**	102,830	4,421
Per share – basic *($)*	**0.09**	0.01	800
Per share – diluted *($)*	**0.09**	0.01	800
Net Income (loss) *($)*	**2,597,687**	(9,065,878)	129
Per share – basic *($)*	**0.05**	(0.49)	110
Per share – diluted *($)*	**0.05**	(0.49)	110
Common Shares Outstanding			
End of Period	**60,792,679**	32,198,218	89
Weighted Average For Period *(basic and diluted)*	**54,768,235**	18,567,707	195
Capital Expenditures, net *($)*	**21,354,031**	8,166,387	161
Working Capital (Deficiency) *($)*	**(811,355)**	(623,928)	30
Revolving Production Loan *($)*	**7,458,345**	–	

TRANSACTIONAL ACTIVITIES

- **February 2002**
  $9,749,000 net acquisition cost of central Alberta light oil and natural gas properties
- **October 2002**
  $2,206,400 private placement of common shares
- **July – November 2002**
  acquired additional interests at Haynes from various joint interest holders for approximately $745,000
- **December 2002**
  $200,000 private placement of common shares on a flow-through basis

DEAR SHAREHOLDERS,

On behalf of the management, staff and directors I am pleased to report that in 2002 Case established itself as a recognized junior oil and gas producer. Cash flow in the fourth quarter rose to $2,545,603 compared to $50,122 in the fourth quarter of 2001, a 4,979% increase. Average production in the fourth quarter of 2002 was approximately 1692 boe/day (6 to 1). This compared to average production in the fourth quarter of 2001 of 432 boe/day, a 292% increase. This production increase and resulting cash flow were a direct result of our team's efforts in identifying the potential of the Haynes property in central Alberta, negotiating the purchase of the property on reasonable terms, quickly developing an exploitation plan and efficiently and promptly executing that exploitation program.

It is important to note that average fourth quarter production of 1,692 boe/day was an increase of 649 boe/day over the 2002 third quarter average of 1,043 boe/day or approximately 62%. Fourth quarter cash flow of $2,545,603 was an increase of $1,372,049 or 116% over the third quarter cash flow of $1,173,554. Increased production, together with high commodity prices produced significant cash flow in the fourth quarter.

As I have reported earlier, our Haynes property, along with several other central Alberta properties, was purchased in February 2002, for a net price of approximately $10 million and I am proud to say that its value is far greater today as a result of our team's work over the past year.

Coincident with purchasing the Haynes property, Case closed an equity issue for $7.5 million, at 30¢ per share. This issue was completed well before the current heated equity markets and we thank the subscribers for their support.

Immediately upon completion of the central Alberta acquisition our team planned and executed phase I of the exploitation and development plan for Haynes. This included the shooting of a 3D seismic program over the Haynes field, followed by the processing and review of the seismic data. This led to the posting and purchase of additional Leduc rights associated with the Haynes field which ultimately were acquired for approximately $1 million. Our most successful oil and gas well to date was eventually drilled on these new lands. After the purchase of the Leduc rights, we set out to exploit the field. This included the successful drilling, completion and tie in of three 100% working interest infill Nisku 40° light oil wells and one 100% working interest Leduc/ Nisku dual producing 40° light oil and sour gas well. In late December 2002, we drilled two shallow sweet gas wells which have very recently been tied in and are now on production.

Further, we optimized the production facilities at Haynes including spending approximately $900,000 on the upgrading and modification of the facilities in December 2002. In conjunction with the exploitation of this Haynes field we negotiated the acquisition of additional working interests in the Haynes field and divested of certain minor working interests in miscellaneous properties in order to focus our efforts at Haynes and to reduce both our debt and our time commitment to properties which had no significant upside value to Case.

In conjunction with the production additions and the increasing cash flows we continued to add high quality technical people to our team whose skills and expertise will ultimately fuel our growth in the future.

In summary, during 2002 we exceeded our production, cash flow, and reserve addition targets. We now have close to 100% of the Haynes property, the oil facilities, and the gas gathering and compression facilities, plus 40% of the Haynes Pipeline which transports natural gas to the Nevis sour gas plant gathering system.

Looking forward to 2003 and beyond, we expect to drill and tie-in up to 4 infill wells on the Haynes property by July 30, 2003 and thereafter review a number of contingent locations based on the results of the current infill program. We have ear-marked just over $2 million for exploration activities in 2003 and we believe that this allocation of capital will plant the seeds for growth.

We have subsequent to year end, sold slightly more than half of our heavy oil properties and substantially all of our other miscellaneous interests in a series of transactions. These dispositions will have the effect of continuing to reduce our operating costs, and have significantly reduced Case's debt, creating a very healthy balance sheet. The current commodity prices and the fact that our production is unhedged, (except for 100 barrels of heavy oil), is contributing to an unexpected increase in cash flow which is further reducing our debt. Case now has the financial ability to execute a substantial acquisition or to undertake a sizeable drilling project without having to raise equity.

Thank you to our directors, management and staff for their efforts in 2002. Our future looks extremely bright.

On behalf of management and directors,

Jeff Tonken

A. Jeffery Tonken
President and Chief Executive Officer

April 1, 2003

OPERATIONS

Overview

2002 was a successful transition year for Case with the Corporation significantly upgrading the quality of its asset base. Throughout the year Case divested of properties that contained low rate, high operating cost wells and non-operated properties with low working interests. At the same time Case acquired additional interests in the Haynes area which is now the main focus area of the Corporation.

The Haynes property has a number of positive attributes:

- high rate light oil wells with low operating cost
- multi-zone exploitation potential
- high working interest ownership and control of production infrastructure
- geographic focus
- year round access

A more complete description of the Haynes property is provided below.

Production

During 2002, Case produced an average of 1073 boe/d consisting of 532 bbls/d of light oil, 348 bbls/d of heavy oil and 853 mcf/d of natural gas and 51 bbls/d of natural gas liquids. Average production was up over 233% over the prior year largely as a result of the Haynes property acquisition and the result of the drilling and recompletion work at Haynes. The following table provides a breakdown of 2002 production by area and by commodity.

	Light Oil (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbls/d)	Barrels of Oil Equivalent (boe/d @ 6:1)
Haynes (original Haynes south)	29		25	1	34
Haynes Acquired	419		414	40	528
Heavy Oil	–	348	31	–	353
Miscellaneous	84		383	10	158
Total	**532**	**348**	**853**	**51**	**1,073**

Drilling Activities

Case participated in the drilling of 7 (5.84 net) wells during 2002 resulting in 4 (4.00 net) oil wells and 3 (1.84 net) natural gas wells. The drilling operations for six (5.65 net) wells were operated by Case and the drilling of one (0.19 net) well was operated by a third party. All of the wells were cased, completed and brought on production resulting in a 100% drilling success ratio.

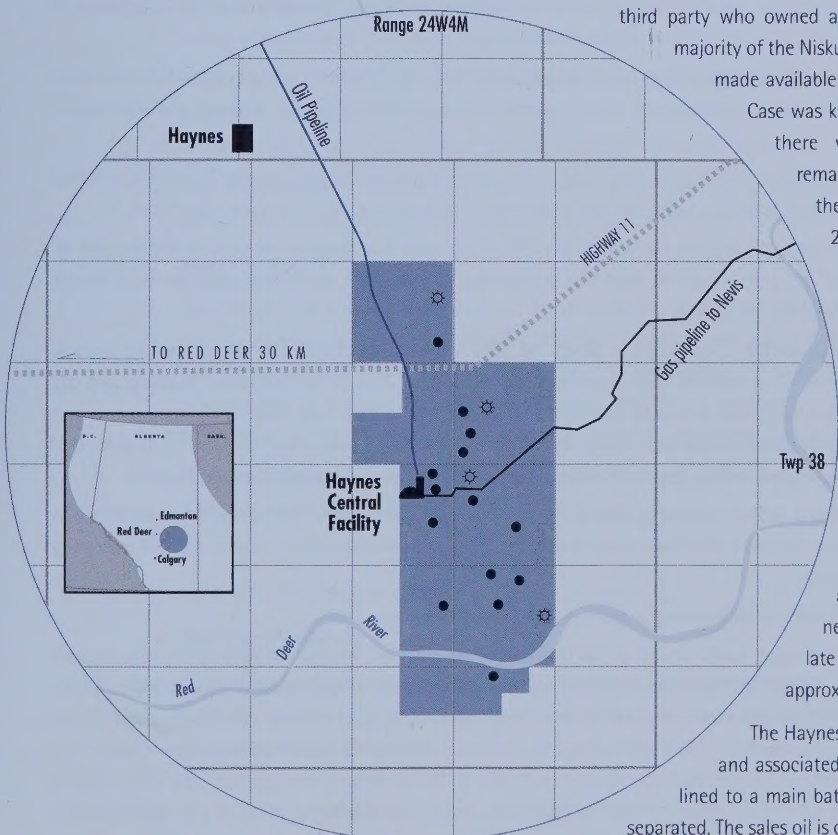
	Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil	4	4.00	0	0.00	4	4.00
Natural Gas	2	1.65	1	0.19	3	1.84
Dry and Abandoned	0	0.00	0	0.00	0	0.00
Total	**6**	**5.65**	**1**	**0.19**	**7**	**5.84**

The four operated oil wells and two operated natural gas wells were all drilled in the recently acquired Haynes property.

Properties

Haynes

The Haynes field is located 30 kilometers east of Red Deer, in Township 38, Range 24 W4M. The main producing intervals are the Nisku (D2) and Leduc (D3) which both contain sour 40° API light oil. Shallow gas is produced in the area from the Glauconitic, Ellerslie and Belly River formations. Case operated several low working interest wells in the area for a number of years and owned limited undeveloped acreage in the area. All of Case's production was processed by a third party who owned and controlled the infrastructure and the vast majority of the Nisku and Leduc pools. In late 2001 this property was made available for purchase through a public auction process. Case was knowledgeable about the area and believed that there was considerable exploitation opportunity remaining in this property. Case successfully acquired the property via the auction process on February 28, 2002 and at the time of closing the acquisition, Case's total production from this property was approximately 400 boe/d.



During the remaining 10 months of 2002 Case was very active in developing and implementing a development program for this property resulting in capital expenditures in excess of $8 million during 2002. As a result of this activity, by the end of 2002, production had risen to approximately 1100 boe/d. Further production additions of approximately 100 boe/d are expected in the near term as a result of spending that occurred late in December. This represents an increase of approximately 800 boe/d which is a 200% increase.

The Haynes property produces a sour light high quality oil and associated sour gas from 14 wells all of which are flow-lined to a main battery location where water and natural gas are separated. The sales oil is delivered into a Koch pipeline at the battery and the natural gas is compressed at Case's main battery and delivered for processing into the Haynes Pipeline (40% owned by Case) which connects to the gathering system for the Nevis sour gas plant. Processed natural gas enters the Nova system at the outlet from the Nevis plant. The water that is removed from the effluent stream at Haynes is injected into a disposal well at the Haynes site. Fuel gas for the Haynes battery is obtained from 4 sweet shallow gas wells at Haynes in which Case has a working interest.

Case takes considerable precautions on an ongoing basis to prevent accidental releases of sour gas from the sour gas facility and to ensure that no harm or loss results to anyone or anything.

A brief summary of the activities undertaken by Case at Haynes during 2002 includes:

- Immediately after purchasing the Haynes property, Case completed a 3D seismic survey over a substantial portion of the pool at a cost of approximately $550,000. This seismic data was used to generate detailed subsurface maps which provided key information used in selecting infill drilling locations.
- Case also began a recompletion program immediately after taking over the property. The first well recompletion was very successful and resulted in an increase in production of over 100 bbls/d of oil. A further three recompletions were undertaken but the age of the wellbores limited the scope of the operations and the results were disappointing. The Corporation is carefully evaluating the viability of its other recompletion opportunities.
- In order to facilitate the infill drilling program Case posted and acquired from the Alberta Crown land sale additional Leduc mineral rights. Case was able to drill a successful well into the landsale which allowed us to better evaluate and aggressively bid on selected parcels.
- Case successfully drilled two infill wells in August and an additional two infill wells in October of 2002. This drilling resulted in three Nisku oil wells and one dual Nisku / Leduc well. All wells were completed and tied in by mid - December.
- Case drilled two successful exploratory shallow gas wells in late 2002. Both wells have recently been tied in and brought on production. Case is pleased with the results to date but is planning to undertake additional technical work before proceeding with additional shallow gas drilling.
- With the large increase in production (400 boe/d in March to 1100 boe/d in December) Case expanded the existing production facilities at Haynes. Case invested approximately $900,000 in late 2002 to increase fluid handling and gas compression capacity. The Haynes facility should be able to now handle the projected fluid volumes for the next several years, including increased water production as water cuts increase. Excess gas compression capacity may be fully utilized in the next 6 -12 months depending on drilling results. Additional compression will be added to the extent required.
- Case has an ongoing initiative to reduce operating costs at Haynes. Unit operating costs at Haynes averaged $4.96/boe in 2002 and are expected to drop further in 2003 as a result of bringing on additional production volumes without increasing the operating costs significantly.
- Cases completed three additional, complimentary property acquisitions in the Haynes area.
- Case organized and hosted two open house forums at the Haynes Community Hall for local residents. These open houses were held at Case's initiative for the purpose of keeping local residents informed as to Case's upcoming plans and to obtain feedback on any concerns that local residents might have with Case's operations. Each of these open house forums were well attended by Case's senior management and field operations personnel and also by local residents in the Haynes area. Because the production facility at Haynes is a sour facility and most of the oil wells in the area are sour wells, Case is dedicated to working closely with its neighbours in the Haynes area to ensure that they are apprised of our future plans so that issues resulting from Case's increased activities can be properly addressed in a constructive manner.

Case plans to continue to be very active in the Haynes area during 2003. Four additional Nisku/Leduc wells are planned for 2003 with further contingent locations to be evaluated based on results from the first four wells. We have not planned any additional Nisku/Leduc recompletions in 2003 given the mixed results to date. Drilling for shallow gas is currently being evaluated. No new shallow gas wells have been included in the budget for 2003 however this may change depending on the results of the technical work and production performance of the wells drilled in late 2002. Minor additional facility modifications will also be undertaken at Haynes in 2003.

Heavy Oil Properties – Lloydminster Area

Throughout 2002, Case had a 50% working interest in a number of heavy oil properties located primarily in the West Hazel, Turtleford and Englishman Lake areas of Saskatchewan which are approximately 60 kilometers east of Lloydminster. Essentially all of the production in this area was from the West Hazel property and averaged 348 bbls/d net to Case in 2002. The average gravity of this production is approximately 12 - 14° API. Operating costs for these properties were $7.67/bbl and netbacks were $9.75/bbl.

No drilling activity occurred in 2002 however a number of the wells were successfully recompleted uphole. As a result production increased throughout the period.

In early 2003, Case sold half of its 50% working interest at West Hazel and all of its remaining interests in its other heavy oil properties. This transaction closed on February 28, 2003 and Case's only remaining interest in heavy oil properties is a 25% working interest in West Hazel. Case's share of current production from this property is approximately 185 bbls/day.

Case had planned for three new infill wells at West Hazel during 2003. The new Operator of this property has indicated that it plans to be more aggressive in the development of this property and it is likely that more than three wells will be drilled in 2003.

Miscellaneous Properties

Case has varying interests in a number of minor properties that produced a total of 158 boe/day in 2002 (84 bbls/day of light oil, 383 mcf/day of natural gas and 10 bbls/day of natural gas liquids liquids). Several of these properties contain low productivity wells that have high operating costs and low netbacks. In early 2003 Case entered into an agreement to dispose of essentially all of these interests for a purchase price, before adjustments, of $3,700,000 and Case is holding a deposit of $370,000 to secure the purchaser's obligation to complete this transaction. This transaction is scheduled to close in mid-April.

The Corporation's interests in the Acheson area were disposed of effective April 1, 2002 for an aggregate purchase price of $348,000 after final adjustments.

RESERVES EVALUATION

Third Party Engineering

An independent evaluation of Case's reserves was prepared by Gilbert, Lausten Jung and Associated Ltd ("GLJ") as of January 1, 2003. The reserve estimates were prepared based on a review of the reservoir and performance characteristics, as well as historical revenues and costs.

Escalated Pricing and Costs

The following table sets forth a summary of the Corporation's Reserves as at January 1, 2003 based on GLJ's forecast of commodity prices and, exchange rates and inflated operating and capital costs:

	Reserves Summary [1,2]								Estimated Future Net Cash Flow Discounted at ($000's)			
	Light Oil & NGL's (mbbls)		Heavy Oil (mbbls)		Natural Gas (mmcf)		BOE @ 6:1 (mboe)					
Reserve Category	Gross	Net	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
Proved Developed Producing	1,904	1,483	436	391	3,393	2,649	2,906	2,316	45,124	33,457	29,976	27,309
Proven Undeveloped /Non-Producing	988	817	126	116	1,463	1,099	1,357	1,115	21,850	13,037	10,532	8,705
Total Proven	2,892	2,300	562	507	4,856	3,748	4,263	3,431	66,974	46,494	40,508	36,014
Probable	924	761	394	348	1,898	1,471	1,634	1,354	27,636	11,981	8,937	7,056
Total Proven + Probable	3,815	3,061	957	855	6,754	5,219	5,898	4,786	94,610	58,475	49,445	43,070
Established (Proven + 1/2 Probable)	3,354	2,681	759	681	5,805	4,484	5,081	4,109	80,792	52,484	44,977	39,542

1. Gross Reserves are the Corporation's interest before deduction of royalties
2. Net Reserves are the Corporation's interest after the deduction of royalties

GLJ's forecast commodity prices, exchange rates and inflation rate is as follows:

Year	Oil WTI (US$/bbl)	Gas [1] Average (C$/mmbtu)	Exchange Rate (US$/C$)	Inflation Rate (%)
2003	25.50	5.40	0.65	1.5
2004	22.00	4.80	0.66	1.5
2005	21.00	4.50	0.67	1.5
2006	21.00	4.65	0.67	1.5
2007	21.25	4.65	0.68	1.5
2008	21.75	4.65	0.68	1.5
2009	22.00	4.65	0.68	1.5
2010	22.25	4.70	0.68	1.5
2011	22.50	4.75	0.68	1.5
2012	23.00	4.85	0.68	1.5

(1) Alberta Plant Gate price before gathering and processing charges

Constant Pricing and Costs

The following table sets forth a summary of the Corporations reserves as at January 1, 2003 based on constant Edmonton Par prices of C$44.77/bbl oil and liquids and an average AECO-C price of C$6.12/mmbtu and no inflation for operating and equipment costs:

	Reserves Summary [1,2]								Estimated Future Net Cash Flow Discounted at ($000's)			
	Light Oil & NGL's (mbbls)		Heavy Oil (mbbls)		Natural Gas (mmcf)		BOE @ 6:1 (mboe)					
Reserve Category	Gross	Net	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
Proved Developed Producing	1,956	1,509	462	412	3,432	2,677	2,990	2,367	70,476	49,915	44,010	39,566
Proven Undeveloped /Non-Producing	987	807	134	123	1,463	1,099	1,364	1,114	34,398	20,788	16,920	14,096
Total Proven	2,943	2,316	596	535	4,895	3,776	4,354	3,481	104,874	70,703	60,930	53,662
Probable	949	774	414	362	1,911	1,479	1,682	1,382	41,231	17,566	13,071	10,300
Total Proven + Probable	3,892	3,090	1,010	897	6,806	5,255	6,036	4,863	146,105	88,269	74,001	63,962
Established (Proven + 1/2 Probable)	3,417	2,703	803	716	5,851	4,516	5,195	4,172	125,490	79,486	67,466	58,812

1. Gross Reserves are the Corporation's interest before deduction of royalties
2. Net Reserves are the Corporation's interest after the deduction of royalties

Gross Reserve Reconciliation

The following table sets forth the reconciliation of Case's gross proven and probable reserves as at January 1, 2003.

	Light Oil & NGL's (mbbls)		Heavy Oil (mbbls)		Natural Gas (mmcf)		BOE @ 6:1 (mboe)		
	Proven	Probable	Proven	Probable	Proven	Probable	Proven	Probable	Established
Reserves at January 1, 2002	128	83	582	234	95	87	726	332	892
Acquisitions and Divestments	1,286	683	0	0	2,072	687	1,631	798	2,030
Drilling and Development	1,703	97	107	161	2,978	881	2,306	405	2,509
Production	(213)	–	(127)	–	(311)	–	(392)	–	(392)
Revisions	(12)	60	N/M[1]	N/M[1]	23	242	(8)	100	42
Reserves at January 1, 2003	**2,892**	**924**	**562**	**394**	**4,856**	**1,898**	**4,263**	**1,634**	**5,081**

1. N/M indicates a non-material amount

Effect of Actual and Proposed Property Sales - Post December 31, 2002 Closings

As disclosed above, effective February 28, 2003 the Corporation sold approximately half of its heavy oil reserves. Furthermore, the Corporation has entered into an agreement to sell essentially all of its remaining minor properties with an anticipated closing date of mid-April, 2003. The following table takes these dispositions into effect and presents Case's remaining reserves:

	Reserves Summary [1,2]								Estimated Future Net Cash Flow Discounted at ($000's)			
	Light Oil & NGL's (mbbls)		Heavy Oil (mbbls)		Natural Gas (mmcf)		BOE @ 6:1 (mboe)					
Reserve Category	Gross	Net	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
Proved Developed Producing	1,796	1,391	210	189	2110	1,558	2358	1,840	37,490	28,114	25,233	23,008
Proven Undeveloped	987	818	63	58	1,363	1,011	1,277	1,044	21,168	12,649	10,229	8,463
Total Proven	2,783	2,209	273	247	3473	2,569	3635	2,884	58,658	40,763	35,462	31,471
Probable	889	731	193	170	1,418	1,059	1,318	1,078	24,153	10,488	7,811	6,157
Total Proven + Probable	3672	2,940	466	417	4891	3,628	4953	3,962	82,811	51,251	43,273	37,628
Established, Proven + 1/2 Probable	3,228	2,574	370	332	4,182	3,099	4,294	3,423	70,735	46.007	39,368	34,550

1. Gross Reserves are the Corporation's interest before deduction of royalties
2. Net Reserves are the Corporation's interest after the deduction of royalties

Finding and Development Costs

The following table sets forth Case's finding and on-stream costs for each of the 2001 and 2002 years.

	2002		2001	
	Proven	Proven & Probable	Proven	Proven & Probable
Total exploration, development and facility expenditures	$ 11,196,196		$ 4,109,413	
Reserve additions, including revisions and excluding acquisitions/dispositions (MBOE) (6:1)	2,298	2,803	102	(46)
Average cost per BOE	$ 4.87	$ 3.99	$ 40.29	N/A
Acquisition expenditures net of disposition proceeds	$ 10,070,040		$ 4,052,674	
Reserve additions, from acquisitions net of dispositions (MBOE) (6:1)	1,631	2,429	411	635
Average cost per BOE	$ 6.17	$ 4.15	$ 9.86	$ 6.38
Total finding and on-stream costs	$ 21,266,236		$ 8,162,087	
Reserve additions, including revisions (MBOE) (6:1)	3,929	5,232	513	589
Average cost per BOE	$ 5.41	$ 4.06	$ 15.91	$ 13.86

The capital expenditures estimated by GLJ to develop these reserves total $5,358,000 for Proven Reserves and $5,677,000 for Proven plus Probable Reserves.

The following discussion and analysis is management's assessment of Case's historical financial and operating results and should be read in conjunction with the audited comparative consolidated financial statements of the Corporation for the year ended December 31, 2002, together with the notes thereto. Readers should be aware that the following discussion and analysis relates in part to the 2001 fiscal year.

This Annual Report includes forward-looking statements respecting the Corporation's strategies, future operations and expected financial results and discusses issues, risks and uncertainties that can be expected to impact on future operations and expected financial results. Actual future results may differ materially from those described in such forward-looking statements as a result of the impact of such issues, risks and uncertainties which the Corporation may not be able to control. The reader is therefore cautioned not to place undue reliance on such forward-looking statements.

FINANCIAL HIGHLIGHTS

The following table sets forth a summary of the financial highlights of the Corporation for the years ended December 31, 2002 and 2001.

Years Ended December 31 *($, except per share and production amounts)*	2002	2001
Petroleum and natural gas sales	**12,272,209**	3,489,522
Total revenues, net of royalties	**9,632,214**	3,179,788
Cash flow from operations	**4,649,299**	102,830
Basic and diluted per share	**0.09**	0.01
Net Income (loss)	**2,597,687**	(9,065,878)
Basic and diluted per share	**0.05**	(0.49)
Capital expenditures, net	**21,354,031**	8,166,387
Working capital surplus (deficiency)	**(811,355)**	(623,928)
Revolving production loan	**7,458,345**	–
Shareholders' equity	**12,767,059**	1,385,849
Average daily production (boe at 6:1)	**1,073**	322
Common shares outstanding, end of period		
Basic	**60,792,679**	32,198,218
Weighted average common shares outstanding		
Basic and diluted	**54,768,235**	18,567,707

MAJOR TRANSACTIONS AFFECTING FINANCIAL RESULTS

The financial results of the Corporation have been and will continue to be significantly affected by a number of corporate financing and property transactions that were closed in 2001 and 2002. These transactions are summarized below:

1. On July 11, 2001, the Corporation issued by private placement 3,205,443 flow-through common shares at a price of $0.90 per share for gross proceeds of $2,885,000 (net proceeds of $2,713,987 after related costs). The directors and officers of Case subscribed for approximately one third of these common shares.
2. In July 2001, the Corporation acquired from Viracocha Energy Inc. a 50% undivided interest in certain heavy oil properties in the Westhazel, Turtleford and other nearby areas of Saskatchewan for a purchase price of approximately $4 million. Viracocha, as the operator of the properties, is entitled to receive an incentive of up to $1 million if certain operational and production goals are achieved. The threshholds necessary to obtain the incentive payments were not met and consequently no payments were made in this regard. Case is also entitled to participate with Viracocha in its heavy oil opportunities that it currently has or develops in Saskatchewan.

3. On December 14, 2001, the Corporation completed a private placement of 12,823,000 common shares at a price of $0.20 per share for gross proceeds of $2,564,600 (net proceeds of $2,561,185 after related costs).
4. On February 28, 2002, the Corporation closed a $12,000,000 (before adjustments) acquisition of light oil and natural gas producing properties in central Alberta. The acquisition had an effective date of November 1, 2001 for the purpose of determining the final purchase price. In conjunction with this acquisition some miscellaneous interests were removed from the acquisition by the exercise of rights of first refusal by third parties. As a result the Corporation purchased the central Alberta properties for a total of $10,962,000, and concurrently sold some of the properties for $1,213,000 resulting in a net acquisition price of approximately $9,749,000. In order to finance the acquisition price, the Corporation issued 24,999,999 common shares at $0.30 per share pursuant to a private placement on February 14, 2002 for gross proceeds of $7,500,000 (net proceeds of approximately $7,004,632 after related costs, see Note 5(g) to the consolidated financial statements) and increased its revolving production loan facility.
5. On October 31, 2002, the Corporation completed a private placement of 3,394,462 common shares at a price of $0.65 per share for gross proceeds of $2,206,400 (net proceeds of $2,115,471 after related costs).
6. On December 19, 2002, the Corporation completed a private placement of 200,000 common shares on a flow through basis at a price of $1.00 per share for gross proceeds of $200,000 (net proceeds of $199,050 after related costs).
7. During 2002, the Corporation disposed of some minor none-core properties in the Acheson and Three Hills areas and acquired additional working interests in the Haynes area from three other joint interest owners.
8. In February, 2002 the Corporation increased its available credit facility to $5,975,000, in July, 2002, the Corporation increased its available credit facility to $7,000,000, in September, 2002 the Corporation increased its available credit facility to $8,500,000 and in December, 2002 the Corporation increased its available credit facility to $9,700,000.
9. Subsequent to the end of 2002, (on February 28, 2003) the Corporation disposed of slightly more than one half of its heavy oil properties for an estimated purchase price, after adjustments, of approximately $2,300,000 which resulted in a minor $100,000 net reduction of the Corporation's available credit facility to $9,600,000 after giving consideration to current production from our Haynes field.

LIQUIDITY

The Corporation had a working capital deficit of $811,355 and $7,458,345 of current bank debt at December 31, 2002. This is a slight increase from the prior year working capital deficit of $623,928 and a significant increase in the amount of bank debt as compared to the prior year. Each of these increases is a direct result of the acquisitions completed by the Corporation and the increased capital spending program at Haynes during 2002.

The Corporation has traditionally financed its oil and gas operations primarily through the reinvestment of the Corporation's cash flow from operations, proceeds from bank debt and equity financings. The Corporation expects to be able to continue to raise additional equity and debt financing sufficient to meet both its short-term and long-term growth requirements in the current environment. The Corporation expects to have sufficient cash flow and available credit to complete its budgeted capital expenditure program for 2003 based on the current commodity price environment. The Corporation is expecting an increase in its credit facility based on the results of its 2002 capital program and based on the expected results of its capital expenditure program in 2003. The Corporation is actively working to dispose of additional non-core properties which will provide additional working capital. As disclosed in our press release of March 17, 2003, Case has contracted to sell the majority of its remaining non-core properties for a purchase price of $3.7 million.

The main components of the budgeted capital expenditure program for 2003 includes, the completion of one sweet gas well at Haynes that was drilled in late 2002, installation of artificial lift equipment on wells drilled at Haynes in 2002, a number of well work-overs at Haynes and the drilling, completion and equipping of 4 oil wells at Haynes, and the drilling, completion and equipping of 3 heavy oil wells in Saskatchewan. In addition the Corporation has budgeted to spend approximately $2,000,000 on exploration activities. In total the budgeted capital expenditure program for 2003 is $9,400,000 of which $6,900,000 relates to development and facilities.

The Corporation has not budgeted for any acquisitions during 2003. Management is confident that in the current environment, should an attractive acquisition opportunity arise the Corporation is in a position to raise sufficient equity and/or debt financing to allow it to pursue that opportunity. Given the current commodity price environment, management believes that the Corporation should be able to debt finance acquisition opportunities of up to $15 million without issuing additional equity.

The major risk factors affecting the Corporation's liquidity are commodity prices for light oil, natural gas and to a much lesser degree heavy oil and the uncertainty of achieving planned production from the expenditure of capital on development and exploration projects. The commodity price environment is currently very strong. However, the commodity price is unpredictable and therefore the Corporation may from time to time fix the commodity price for future periods on some of its production. See the heading under MD&A entitled "Petroleum and Natural Gas Sales" and note 9 to the financial statements for details of the current commitments.

The Corporation manages the risks associated with its development and exploration projects by utilizing highly qualified technical and operations teams to identify and then evaluate the Corporation's opportunities. The Corporation's technical and operations teams have extensive experience and are highly qualified to evaluate the Corporation's opportunities. The Corporation's 2003 capital spending is primarily focussed on the Haynes property with approximately 70% of the 2003 capital budget being allocated for that area. Should the capital spending on this property not produce anticipated results, management will have to review the remaining capital expenditure program to ensure the costs of the projects it proceeds with will be within the financial resources available from its cash flow, debt capacity, proceeds, if any, from disposition of non-core properties, and additional equity financing capability at that time.

The Management of Case has a proven track record of being able to raise substantial amounts of equity. Management anticipates that in order for the Corporation to grow substantially over the next few years new equity will be required for significant projects and acquisitions.

Cash Flow from Operations

The Corporation's cash flow from operations of $4,649,299 during the year ended December 31, 2002 is an increase of 4,421% over the cash flow from operations of $102,830 in 2001. This increase in cash flow was due primarily to increased light oil and natural gas sales volumes resulting from the acquisition of the central Alberta properties in February 2002 and the development work that was done at Haynes in the last half of 2002 and to a lesser extent from the impact of a full year's production from the heavy oil properties that were acquired in mid 2001. This increased cash flow also resulted from light oil commodity prices realized by the Corporation which increased by 7% from an average of $36.66 in 2001 to $39.34 in 2002. The cash flow from the central Alberta properties significantly impacted the Corporation's cash flow because the addition of these properties generated material revenues but had minimal effect on the Corporation's staffing and general and administrative expenses. Management expects that the Corporation will have a substantial increase in cash flow from operations in 2003 as a result of the recent strengthening of light oil and natural gas commodity prices, the full year cash flow impact of production increases from the 2002 development program and the expected impact of the 2003 development

program at Haynes. The Corporation expects that its cash flow from operations for the year ended December 31, 2003, given the current commodity price environment, together with anticipated increases in our credit facility will be sufficient to fund our budgeted capital program for 2003.

The two key factors currently influencing the Corporation's cash flow from operations are the level of commodity production and the commodity prices. Although the impact on the Corporation of interruptions in production from individual wells is less than would have been the case during 2001, the Corporation still relies on some relatively high volume oil wells and should an uncontrollable event occur which adversely affects any of those high volume wells, it may significantly affect cash flow.

The Haynes reservoir has a strong bottom water drive that could result in one or more wells watering out prematurely. Drainage patterns in the pool are complicated by the fact that produced water is disposed of back into the reservoir. It is possible that infill wells may be drilled into parts of the reservoir that have already been drained or swept. It is believed that one of the infill wells drilled in 2002 penetrated a portion of the reservoir that was swept in this manner. Production from this well has not met management's original expectations.

Case has encountered localized secondary gas caps that have resulted from pressure depletion in the pool over the last 40 years. Case's production practice is to blow down these localized gas cap as we now believe that no detrimental long term effects will result but insufficient production history exists at this time to properly determine the long term impact of this operating strategy.

In addition, the Corporation's ability to produce its sour wells at Haynes which comprise approximately 70% of its current production is dependent upon its continued ability to process its production through its own battery located at Haynes and its ability to transport and process the associated sour solution gas at the Nevis Plant which is owned and operated by a third party. Any significant outage at either of these facilities would have a material adverse effect on the Corporation's production volumes and resulting cash flows. The Corporation carries business interruption insurance to mitigate these processing plant risks but an extended outage exceeding 6 months would significantly and adversely affect the Corporation's cash flows and business plan.

Sensitivity Analysis

The following table set forth management's estimate of the sensitivity of expected cash flow to be generated by the Corporation during the period January 1, 2003 through to December 31, 2003 based on the budget approved by the Corporation's Board of Directors, which includes numerous assumptions. The budget includes a significant capital expenditure program on the Haynes field (approximately $6,600,000) and approximately $2,000,000 of exploration related expenditures. The 2003 budget does not contemplate any acquisitions. It does however include the disposition of just over 50% of our heavy oil properties for estimated proceeds of $2,400,000. This sale is budgeted to close on February 28, 2003 and did in fact close on that date.

Factor	2003 Budget		Variance in Factor		Variance in Cash Flow	
WTI oil price	$US	25.00	US	$1.00/bbl	CDN$	543,000
Natural gas spot price	$CDN	4.75	CDN	$0.10/mcf	CDN$	54,000
Lloyd Blend Differential	$US	$8.00	US	$1.00/bbl	CDN$	48,000
CDN$/US$	1.5625		CDN	$0.01	CDN$	87,000
Prime rate	4.75%			1.0%	CDN$	76,000

Bank Debt

As a result of the capital expenditures incurred by the Corporation in acquiring and developing its Haynes property, the production loan increased from NIL at the end of 2001 to $7,458,345 at the end of 2002. In addition the Corporation's working capital deficit increased moderately to $811,355 at the end of 2002 from $623,928 at the end of the prior year. The Corporation currently has in place a $9,600,000 demand revolving production credit facility with a major lending institution. Outstanding indebtedness bears interest at the institution's prime lending rate plus 1%. At March 28, 2003 the amount outstanding under this credit facility (excluding accruals) was approximately $3.9 million.

Management's intent is to work closely with its credit facility provider to increase the credit facility based upon the reserves resulting from the prior year's development program and based upon the increase in proved producing reserves expected to result from the 2003 capital expenditure program at Haynes. Given the current commodity price environment and given the fact the Corporation's light oil and natural gas is not hedged, the Corporation expects that its bank indebtedness will decline during 2003 thereby providing the Corporation with operational and financial flexibility to capitalize on opportunities that materialize.

Equity Issues

The following table summarizes the common shares issued during 2002 and 2001.

	Common Shares
Balance at December 31, 2000	16,024,775
Exercise of Options and Warrants	145,000
Private Placements	16,028,443
Balance at December 31, 2001	32,198,218
Exercise of Options and Warrants	0
Private Placements	28,594,461
Balance at December 31, 2002	**60,792,679**

For details of the equity issues see Note 5 of the December 31, 2002 consolidated financial statements.

RESULTS OF OPERATIONS

Petroleum and Natural Gas Sales

Petroleum and natural gas sales for the year ended December 31, 2002 were $12,272,209, which represents a 252% increase over the $3,489,522 realized in 2001. This increase in sales is primarily a result of the impact of the production from the central Alberta properties acquired in February 2002 and to a lesser extent a full year of sales from the heavy oil acquisition completed in July 2001. Average daily production for the year ended December 31, 2002 was 1073 boe per day as compared to 322 boe per day realized for the same period in 2001. The increase in sales revenues as a result of increased production was enhanced by a 7% increase in light oil prices realized by the Corporation which was offset somewhat by slightly lower heavy oil (-9%) and natural gas prices (-14%) realized in 2001. The Corporation's average sales price for the year ended December 31, 2002 was $31.14 per boe as compared to $29.70 per boe received in 2001. Approximately 54% of the Corporation's average production was light oil and natural gas liquids, 32% was heavy oil and 14% was natural gas during the 2002 fiscal year.

The following table sets forth Case's average production and prices received for its two most recently completed fiscal periods:

Years Ended December 31	2002	2001
Light oil		
Average daily production (bbl)	532	150
Average sales price (per bbl)	$ 39.34	$ 36.66
Heavy oil		
Average daily production (bbl)	348	147
Average sales price (per bbl)	$ 20.23	$ 22.23
Natural gas		
Average daily production (mcf)	853	138
Average sales price (per mcf)	$ 4.49	$ 5.24
Natural gas liquids		
Average daily production (bbl)	51	2
Average sales price (per bbl)	$ 31.82	$ 37.78
Average daily production (boe)	1,073	322
Average sales price (per boe)	$ 31.14	$ 29.70

The price the Corporation receives for its crude oil depends on a number of factors, including U.S. dollar oil prices, the U.S./Canadian dollar exchange rate, and transportation and product quality differentials. Case regularly considers managing the risk associated with fluctuating U.S. dollar oil prices and the U.S./Canadian dollar exchange rate. In order to manage the risk the Corporation may enter into forward sale contracts, U.S. dollar oil price hedges and/or forward foreign exchange contracts.

From January 1 to December 31, 2002 the Corporation sold forward 150 bbls/d of heavy oil at a WTI price of Cdn $36.94 and at a Light Lloyd Blend at Hardisty differential of US$9.60. For the same time period, the Corporation also sold forward 50 bbls/d of heavy oil at a WTI price of Cdn. $32.21 and at a Light Lloyd Blend differential of US$ 7.20. The Corporation has entered into a forward sale for the 2003 calendar year which fixes a price of Cdn $24.87 for Light Lloyd Blend at Hardisty on a volume of 100 bbls/d of heavy oil.

Royalties and ARTC

Royalties, net of ARTC, in the year ended December 31, 2002 were $2,647,660, which represents a 579% increase from the $390,194 incurred in 2001. This increase is primarily a result of the impact of the production from the Haynes property acquired in February 2002 and to a lesser extent a full year of sales from the heavy oil properties acquired in July 2001. The increase in the average royalty rate from 11% in 2001 to 22% in 2002 resulted from the Haynes property for which royalty rates averaged approximately 27% in 2002 and to a lesser extent from the full year impact of the heavy oil properties for which royalty rates averaged approximately 17% in 2002. The Haynes property contributed approximately 52% of the Corporation's 2002 annual production on a boe basis. The heavy oil properties, which produce a small amount of natural gas, were approximately 33% of the Corporation's 2002 average production on a boe basis.

Operating costs

Operating costs in the year ended December 31, 2002 were $2,823,502, which is an 88% increase over the $1,500,579 incurred in 2001. This increase is primarily a result of the impact of the central Alberta properties acquired in February 2002 and to a lesser extent a full year of sales from the heavy oil properties acquired in July 2001. On a per unit basis, operating costs decreased approximately 44% in 2002 to $7.21 per boe from $12.77 per boe in 2001. The lower unit costs were

primarily a result of the Corporation's acquisition of the Haynes property, which averaged $4.96 per boe for 2002 and to a lesser extent from the heavy oil properties which averaged $7.67 per boe for 2002. As production continues to increase at Haynes, operating costs on a unit basis, are expected to decline further.

General and Administrative Expense

General and administrative costs in the year ended December 31, 2002 were $1,892,176, which represents a 27% increase over the $1,488,163, incurred in 2001. This increase is due primarily to increased personnel costs as a result of the central Alberta acquisition and a greater focus on generating new core areas based on exploration. On a per unit basis, general and administrative costs decreased approximately 62% in the current period to $4.83 per boe from $12.67 per boe in 2001, primarily as a result of increased production due to the central Alberta acquisition in February 2002 and the full year impact of the heavy oil acquisition completed in July 2001. The components of G&A are as follows:

General & Administrative Expenses

Years Ended December 31 (thousands)	2002 $	2001 $
Salaries, fees and consultants	**1,776**	1,148
Other	**606**	648
G & A expense gross	**2,382**	1,796
Overhead recoveries	**(145)**	(175)
Capitalized overhead	**(345)**	(133)
G & A expense net	**1,892**	1,488

Interest Expense

Interest expense in the year ended December 31, 2002 was $212,461. The prior year interest expense was $21,016. This increase is due primarily to the central Alberta acquisition in February 2002 and to the increased capital expenditure program in 2002 on the Haynes field.

Depletion and Depreciation Expense

Depletion and depreciation expense in the year ended December 31, 2002 was $2,416,242, which represents a 73% increase over the $1,398,581 incurred in 2001. This increase is due primarily to the acquisition of the central Alberta properties and the increased capital costs associated with these properties. On a per boe basis depletion and depreciation decreased in 2002 from $11.91 per boe in 2001 to $6.17 per boe primarily due to the increased reserve base associated with the central Alberta acquisition and also due to the write-down of petroleum and natural gas properties in 2001, which reduced the costs subject to depletion for future periods.

Provision for future site restoration costs

Site restoration expense in the year ended December 31, 2002 was $171,000, which represents a 40% increase over the $122,000 incurred in 2001. The increase is due primarily to the abandonment liabilities relating to the central Alberta properties acquired in February 2002. On a per boe basis the amounts are $0.44 per boe for 2002 and $1.04 per boe for 2001.

Write-Down of Petroleum and Natural Gas Properties

The Corporation follows the full cost method of accounting that requires the Corporation to apply a quarterly ceiling test to ensure that capitalized costs do not exceed the estimated value of future net revenues from the production of proved reserves less certain indirect costs associated with such production.

The Corporation conducted a ceiling test calculation at December 31, 2002. The sales prices, in Canadian dollars, at the wellhead used for the ceiling test were $39.62 per barrel for oil and $6.16 per thousand cubic feet for natural gas. As a result of the ceiling test computation, the Corporation is not required to write-down its petroleum and natural gas properties.

The Corporation conducted an interim ceiling test calculation at September 30, 2001. The sales prices, in Canadian dollars, at the wellhead used for the ceiling test were the Corporation's September 2001 average prices of $36.27 per barrel for light oil, $18.66 per barrel for heavy oil and $2.30 per thousand cubic feet for natural gas. As a result of the ceiling test computation, the Corporation has written down its petroleum and natural gas properties by $5,100,000 for the quarter ended September 30, 2001.

The Corporation conducted a further ceiling test calculation at December 31, 2001. The sales prices, in Canadian dollars, at the wellhead used for the ceiling test were $27.27 per barrel for light oil, $12.69 per barrel for heavy oil and $3.32 per thousand cubic feet for natural gas. As a result of the ceiling test computation, the Corporation has written down its petroleum and natural gas properties by a further $3,800,000 for the quarter ended December 31, 2001.

The total write-down of petroleum and natural gas properties for the year ended December 31, 2001 is $8,900,000.

Taxes

The Corporation did not pay any income taxes in the twelve-month period ending December 31, 2002 or 2001. However the Corporation was required to pay cash taxes of $54,776 (2001 - $67,200) under Part XII.6 of the Income Tax Act and was also required to pay the Federal Large Corporations tax. In the current year the Corporation has paid $28,776 (2001 - $67,200) in current taxes relating to Part XII.6 tax. This tax is a function of the time elapsed from the time resource expenditures are renounced to investors to the time at which the resource expenditures are actually incurred by the Corporation. The Corporation paid $26,000 (2001 - NIL) relating to the Federal Large Corporations tax.

The Corporation recorded a future income tax recovery of $535,630 (2001 - $1,251,873) in its 2002 fiscal year, to reduce its future tax liability to $NIL because during the year the Corporation incurred expenditures that had been previously renounced to flow-through share subscribers in accordance with current tax legislation. The Corporation has the required amount of tax deductions available to it to be able to reduce the liability (resulting from the renounced expenditures) to $NIL. The Corporation has decided not to record the benefits of its remaining future tax deductions available as a future income tax benefit on its balance sheet.

NET EARNINGS AND CASH FLOW FROM OPERATIONS

The Corporation recorded net income of $2,597,687 in the year ended December 31, 2002 compared to a loss of $9,065,878 realized in 2001. Most of the 2001 net loss ($8,900,000) results from the ceiling test write-down described above. The net income was achieved through the high quality of the Haynes property acquired in February, 2002 and through economies of scale as the Corporation has been increasing its production base.

Cash flow for the year ended December 31, 2002 was $4,649,299, an increase of 4,421% over the cash flow of $102,830 in 2001. This increase was due primarily to increased production realized in 2002 as a result of the central Alberta acquisition and the development work that was done at Haynes in the last half of 2002 and to a lesser extent from the impact of a full year's production from the heavy oil properties that were acquired in mid 2001. This increased cash flow also resulted from light oil commodity prices realized by the Corporation which increased by 7% from an average of $36.66 in 2001 to $39.34 in 2002.

The increase in cash flow per share from $0.01 in 2001 to $0.09 in 2002, while significant (800%), was substantially less than on an absolute basis as a result of the substantial increase of 195% in the weighted average number of shares outstanding from approximately 18.6 million to approximately 54.8 million shares.

CAPITAL EXPENDITURES AND CAPITAL RESOURCES

The Corporation's net capital expenditures amounted to $21,354,031 in the year ended December 31, 2002 as compared to $8,166,387 in 2001. The increase in capital expenditures in 2002 over 2001 capital expenditures reflects the purchase of the central Alberta properties and the ensuing development and drilling activities on the Haynes property in 2002.

The following table sets forth a summary of the Corporation's net capital expenditures incurred for the years ended December 31, 2002 and 2001.

Capital Expenditures, net

Years Ended December 31	2002 $	2001 $
Property acquisitions	**11,715,567**	4,048,628
Property dispositions	**(1,645,527)**	4,046
Land	**1,221,998**	90,418
Exploration - drilling and completions	**1,142,158**	1,239,905
Exploration - seismic	**574,490**	121,192
Exploration - other	**234,445**	309,241
Development - drilling and completions	**4,960,273**	1,616,460
Development - other	**206,742**	47,511
Well equipment and facilities	**2,511,101**	551,956
Capitalized general and administrative expenses	**344,989**	132,730
Corporate acquisitions	**–**	–
Total finding and on-stream costs	**21,266,236**	8,162,087
Administrative assets	**87,795**	4,300
Total Capital Expenditures, net	**21,354,031**	8,166,387

The following table sets forth a summary of the Corporation's capital resources for the years ended December 31, 2002 and 2001:

Capital Resources

Years Ended December 31	2002 $	2001 $
Cash flow from operations	**4,649,299**	102,830
Changes in working capital	**276,811**	790,040
Site restoration costs paid	**(260,193)**	–
Production loan and other long-term liabilities	**7,458,345**	(97,109)
Equity Issues	**9,319,153**	5,338,922
Repurchase of stock options	**–**	(57,500)
Total capital resources	**21,443,415**	6,077,183

QUARTERLY DATA

The following table sets forth a summary of the Corporation's quarterly data for the years ended December 31, 2002 and 2001:

	Year Ended December 31, 2002				Year Ended December 31, 2001			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Total petroleum and natural gas revenue	1,299,093	2,590,623	2,966,785	5,415,708	746,802	575,992	1,282,682	884,046
Total revenue, net of royalties	1,093,838	2,060,178	2,285,222	4,192,976	658,452	538,057	1,113,702	869,577
Net earnings (loss)	(10,952)	224,788	515,753	1,868,098	(331,826)	(473,378)	(4,693,664)	(3,567,010)
Net earnings (loss) per common share basic and diluted	–	–	0.01	0.03	(0.02)	(0.03)	(0.25)	(0.16)
Cash flow from operations	222,486	707,655	1,173,554	2,545,604	(67,679)	(234,254)	354,641	50,122
Cash flow from operations per common share basic and diluted	–	0.01	0.02	0.04	–	(0.01)	0.02	–
Book value of total assets	13,993,331	14,311,674	18,349,879	24,080,759	7,287,784	6,769,023	7,119,319	3,365,534
Demand revolving production loan	4,123,443	4,311,725	6,618,601	7,458,345	–	–	1,064,521	–
Shareholders' equity	8,297,101	8,463,702	8,941,626	12,767,059	6,132,352	5,623,224	2,980,971	1,385,849
Common shares outstanding end of period	57,198,217	57,198,217	57,198,217	60,792,679	16,094,775	16,169,775	19,375,218	32,198,218
Weighted average common shares outstanding basic and diluted	44,975,995	57,198,217	57,198,217	59,514,050	16,059,775	16,103,841	19,026,800	22,999,109

OUTLOOK

Case's management believes that Case's outlook has never been better. We have a high quality asset at Haynes which produces more cash than is required for the development of that asset and is therefore available for re-investment elsewhere. Case also has a strong balance sheet that will enable it to capture future opportunities without having to raise equity financing. Case is presently experiencing higher than expected cash flows as a result of very high commodity prices for both oil and natural gas, which is further reducing Case's already low debt level due to the recent property sales. More importantly, we are also now well positioned with a low operating cost property at Haynes to profitably operate in a lower commodity price environment.

The immediate priority for Case is to identify and capture the next opportunity capable of being the foundation for Case's next core area of operations. We have a team of highly skilled technical experts who are engaged in constantly evaluating opportunities and we firmly believe that the rigorous application of our team's skills will eventually uncover an appropriate opportunity to enhance the value of Case for its shareholders.

Management's Report

To the Shareholders of Case Resources Inc.

The consolidated financial statements of Case Resources Inc. were prepared by management within the acceptable limits of materiality and are in accordance with accounting principles generally accepted in Canada. Management is responsible for ensuring that the financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

The consolidated financial statements have been prepared by management in accordance with the accounting policies as described in the notes to the consolidated financial statements. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. When necessary, such estimates are based on informed judgements made by management.

Management has designed and maintains an appropriate system of internal controls to provide reasonable assurance that all assets are safeguarded and financial records properly maintained to facilitate the preparation of financial statements for reporting purposes.

Deloitte & Touche LLP, an independent firm of Chartered Accountants appointed by shareholders, have conducted an examination of the corporate and accounting records in order to express their opinion on the consolidated financial statements. The Audit Committee, consisting of a majority of non-management directors, has met with representatives of Deloitte & Touche LLP and management in order to determine if management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

Jeff Tonken

A. Jeffery Tonken
President
and Chief Executive Officer

Bruno P. Geremia
Vice President
and Chief Financial Officer

February 28, 2003

Auditors' Report

To the Shareholders of Case Resources Inc.:

We have audited the consolidated balance sheets of Case Resources Inc. as at December 31, 2002 and 2001 and the consolidated statements of earnings (loss) and deficit and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Calgary, Alberta
February 28, 2003

Consolidated Statements of Earnings (Loss) and Deficit

For the Years Ended December 31,

	2002 $	2001 $
REVENUE		
Petroleum and natural gas sales	**12,272,209**	3,489,522
Royalties, net of ARTC	**(2,647,660)**	(390,194)
Other income	**7,665**	80,460
	9,632,214	3,179,788
EXPENSES		
Operating	**2,823,502**	1,500,579
General and administrative	**1,892,176**	1,488,163
Interest	**212,461**	21,016
Depletion and depreciation	**2,587,242**	1,520,581
Write-down of petroleum and natural gas properties *(Note 3)*	**–**	8,900,000
	7,515,381	13,430,339
EARNINGS (LOSS) BEFORE TAXES	**2,116,833**	(10,250,551)
TAXES *(Note 8)*		
Current	**54,776**	67,200
Future income tax recovery	**(535,630)**	(1,251,873)
	(480,854)	(1,184,673)
NET EARNINGS (LOSS)	**2,597,687**	(9,065,878)
DEFICIT, BEGINNING OF YEAR	**(10,015,182)**	(891,804)
Stock option repurchase	**–**	(57,500)
DEFICIT, END OF YEAR	**(7,417,495)**	(10,015,182)
Net earnings (loss) per share - basic and diluted *(Note 6)*	**$ 0.05**	$ (0.49)
Weighted average number of shares - basic and diluted	**54,768,235**	18,567,707

Consolidated Balance Sheets

As at December 31,

	2002 $	2001 $
ASSETS		
CURRENT		
Cash	**112,798**	23,414
Accounts receivable	**2,718,552**	771,841
Deposits and prepaid expenses	**48,417**	307,076
	2,879,767	1,102,331
Petroleum and natural gas properties *(Note 3)*	**21,200,992**	2,263,203
	24,080,759	3,365,534
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	**3,691,122**	1,726,259
Revolving production loan *(Note 4)*	**7,458,345**	–
	11,149,467	1,726,259
Site restoration provision	**164,233**	253,426
	11,313,700	1,979,685
SHAREHOLDERS' EQUITY		
Share capital *(Note 5)*	**20,184,554**	11,401,031
Deficit	**(7,417,495)**	(10,015,182)
	12,767,059	1,385,849
	24,080,759	3,365,534

APPROVED BY THE BOARD

Larry A. Shaw
Director

A. Jeffery Tonken
Director

Consolidated Statements of Cash Flows
For the Years Ended December 31,

	2002 $	2001 $
CASH FLOWS RELATED TO THE FOLLOWING ACTIVITIES:		
OPERATING		
Net earnings (loss)	**2,597,687**	(9,065,878)
Adjustments for:		
Depletion and depreciation	**2,587,242**	1,520,581
Future income tax recovery	**(535,630)**	(1,251,873)
Write-down of petroleum and natural gas properties *(Note 3)*	**–**	8,900,000
Cash flow from operations	**4,649,299**	102,830
Site restoration expenditures	**(260,193)**	–
Changes in non-cash working capital items from operations *(Note 10)*	**276,811**	790,040
	4,665,917	892,870
FINANCING		
Increase to revolving production loan	**7,458,345**	–
Decrease to long-term debt	**–**	(97,109)
Issuance of share capital, net of related expenses *(Note 5)*	**9,319,153**	5,338,922
Stock option repurchase	**–**	(57,500)
	16,777,498	5,184,313
INVESTING		
Petroleum and natural gas properties and equipment	**(11,283,991)**	(4,113,713)
Purchase of petroleum and natural gas properties and equipment *(Note 3)*	**(11,715,567)**	(4,048,628)
Sale of petroleum and natural gas properties and equipment	**1,645,527**	(4,046)
	(21,354,031)	(8,166,387)
NET INCREASE (DECREASE) IN CASH	**89,384**	(2,089,204)
CASH, BEGINNING OF YEAR	**23,414**	2,112,618
CASH, END OF YEAR	**112,798**	23,414

Years Ended December 31, 2002 and 2001

1. INCORPORATION AND NATURE OF OPERATIONS

Case Resources Inc. ("Case") was incorporated under the Business Corporations Act (Alberta) on March 12, 1993 as 558818 Alberta Inc. It changed its name from Touchstone Petroleum Inc. to Case Resources Inc. on May 17, 2001. On January 1, 2002, Case incorporated a wholly-owned subsidiary for the purpose of managing its heavy oil business. Case and its wholly-owned subsidiary, Case Sub Ltd. ("Sub"), (the "Corporation") are currently engaged in the exploration for and the development and acquisition of, petroleum and natural gas reserves in Western Canada.

2. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), within an acceptable level of materiality, utilizing the framework of the accounting policies below.

Basis of accounting

The Corporation's consolidated financial statements include the accounts of Case and its wholly owned subsidiary, Sub. All inter-company transactions and balances have been eliminated upon consolidation.

Measurement uncertainty

The preparation of timely financial statements sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. When necessary, such estimates are based on informed judgements made by management. Actual results could differ materially from those estimated.

Amounts recorded for depletion, depreciation and amortization and amounts used for ceiling test calculations are based on estimates of oil and natural gas reserves which include estimates of future commodity prices, future costs and other relevant assumptions. The Corporation's reserves are estimated and evaluated, at a minimum, annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty and the impact of changes in such estimates on the consolidated financial statements of future periods could be material.

Petroleum and natural gas properties

The Corporation follows the full-cost method of accounting for petroleum and natural gas properties whereby all costs relating to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre and charged against income, as set out below. Such costs may include lease/land acquisition costs, geological and geophysical expenses, lease rentals and other costs on non-producing properties, costs of drilling and completing both productive and non-productive wells, production equipment and corporate expenses directly related to acquisition, exploration and development activities. These costs along with estimated future capital costs in the current reserve report related to the development of proved reserves, net of salvage values are included in the calculation. Costs of acquiring and evaluating unproved properties may be excluded from the depletion base until it is determined whether proved reserves are attributable to the properties or impairment has occurred.

Depletion of petroleum and natural gas properties and depreciation of production equipment is provided on the unit-of-production basis using estimated gross (before royalties) proved oil and natural gas reserves as determined by independent reservoir engineers. Natural gas reserves and production are converted, at a ratio of six thousand cubic feet of natural gas to one barrel of oil, for depletion and depreciation purposes.

Proceeds from the sale of properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would alter the rate of depletion and depreciation by 20% or more.

The Corporation applies a ceiling test quarterly to capitalized costs to ensure that such costs do not exceed the estimated undiscounted value of future net revenues from the production of its total proved reserves, plus the cost of its undeveloped lands net of impairments. Future net revenues are calculated using either period end or period average sales prices and include an allowance for estimated future general and administrative expenses, financing costs, site restoration costs, income tax costs and development expenditures.

Estimated future site restoration and abandonment costs are provided for over the life of the total proved reserves on a unit-of-production basis. Costs are estimated each year by management in consultation with the Corporation's engineers based on current costs and technology in accordance with the current legislation and industry practices. The annual charge is included in the depletion expense and actual site restoration and abandonment expenditures are applied against the accumulated provision account.

A portion of the Corporation's exploration and production activities are conducted jointly with others and, accordingly, the accounts reflect only the Corporation's proportionate interest in such activities.

Revenue recognition

The Corporation records its petroleum and natural gas revenue at the time of physical transfer to a purchaser.

Per share amounts

Basic per share amounts are calculated using the weighted average number of common shares outstanding during the period. The Corporation utilizes the treasury stock method of calculating diluted earnings per share. Under this method, the diluted weighted average number of common shares is calculated assuming the proceeds from the exercise of stock options are to be used to re-purchase common shares of the Corporation at the average market price during the period.

Future income taxes

The Corporation accounts for its income taxes using the liability method. Under this method, future income tax assets and liabilities are determined based on the differences between the financial reporting and tax basis of assets and liabilities using the tax rates anticipated to apply in relevant future periods.

Flow-through shares

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. The Corporation records the carrying value of the expenditures in petroleum and natural gas properties as incurred and concurrently, will also record a future income tax liability in relation to the benefits renounced with a corresponding reduction to share capital.

Stock options

The Corporation's stock-based compensation arrangements are described in Note 6. No compensation expense is recognized for these arrangements when stock options are issued to employees at market prices. Consideration paid by employees on exercise of stock options is credited to share capital.

Financial instruments

The Corporation has determined that the fair value of the financial instruments consisting of current assets and current liabilities are not materially different from the carrying value of such instruments reported on the balance sheet due to their short-term nature. In respect of the revolving production loan, its carrying value is not materially different than its fair value as the facility bears interest charges based on the prevailing prime interest rate. A substantial portion of the Corporation's accounts receivable are with commodity marketers and joint venture partners in the petroleum and natural gas industry and are subject to normal industry credit risk.

The nature of the Corporation's operations result in exposure to fluctuations in commodity prices, currency exchange rates and interest rates. The Corporation may from time to time manage its exposure to these risks through the use of physical contracts or financial instruments. The Corporation is exposed to potential credit losses in the event of non-performance by counterparties to these arrangements. The Corporation tries to mitigate this risk by only dealing with credit worthy counterparties. Gains and losses on derivative contracts are recognized in income in the same period that the transactions are settled. The fair values of derivative contracts are not recorded in the consolidated balance sheets.

3. PETROLEUM AND NATURAL GAS PROPERTIES

		2002	
	Cost $	Accumulated Depletion and Depreciation $	Net Book Value $
Petroleum and natural gas properties	**34,776,773**	**13,691,131**	**21,085,642**
Furniture and office equipment	**155,892**	**40,542**	**115,350**
	34,932,665	**13,731,673**	**21,200,992**

		2001	
	Cost $	Accumulated Depletion and Depreciation $	Net Book Value $
Petroleum and natural gas properties	13,510,538	11,302,131	2,208,407
Furniture and office equipment	68,096	13,300	54,796
	13,578,634	11,315,431	2,263,203

The Company has capitalized general and administrative expenses related to exploration and development activities of $344,989 (2001 - $132,730).

On February 28, 2002 the Corporation completed an acquisition of light oil and natural gas producing properties in central Alberta. The acquisition had an effective date of November 1, 2001 only for the purpose of determining the final purchase price. After taking into account the four month adjustment period from November 1, 2001 to February 28, 2002, the acquisition price recorded in 2002 is $10,961,972. The Corporation has recorded production volumes, revenue and expenses only from March 1, 2002 forward.

The Corporation has satisfied all of its obligations with respect to all of its flow-through share subscription agreements.

During 2002, the total net book value of expenditures incurred, under the terms of a flow-through share agreement, without tax base is $1,862,558. These expenditures have no cost basis for income tax purposes and they are reflected as such in the computation of future income taxes. With respect to share capital see Note 5.

As at December 31, 2002, the estimated future site restoration costs to be amortized over the remaining proved reserves are $1,426,000 (2001 - $777,974) of which $171,000 (2001 - $122,000) has been included in depletion and depreciation expense in the current year.

In calculating the depletion provision for the year ending December 31, 2002, the carrying value of undeveloped properties that were excluded from the costs subject to depletion were $Nil (2001 - $Nil).

The Corporation conducted a ceiling test calculation at December 31, 2002. The sales prices, in Canadian dollars, at the wellhead used for the ceiling test were $39.62 per barrel for oil, and $6.16 per thousand cubic feet for natural gas. As a result of the ceiling test computation, the Corporation is not required to write down its petroleum and natural gas properties at December 31, 2002.

The total write down of petroleum and natural gas properties required, based on the ceiling test calculation, for the prior year ended December 31, 2001 was $8,900,000.

4. REVOLVING PRODUCTION LOAN FACILITY

At December 31, 2002, the Corporation had a revolving production loan facility (the "facility") with a major lender. Direct borrowings under this facility bear interest at prime plus 1%. The security pledged for the facility consists of a demand debenture in the amount of $20,000,000 providing a floating charge over all of the Corporation's assets.

The maximum amount that can be drawn upon this facility is determined by the lender from time to time after assessing the Corporation's total proved reserves. The Corporation is subject to an annual review in May of each year. At December 31, 2002, the maximum amount available under this facility was $9,700,000 based on the Corporation's then current engineering report, current production reports and the lender's oil and natural gas price forecasts.

Effective January 1, 2002, the Corporation adopted the recommendations of the Canadian Institute of Chartered Accountants ("CICA") concerning the presentation of revolving demand loans. These new recommendations require that the classification of debt in a debtor's balance sheet be based upon the facts existing at the balance sheet date rather than future expectations. Prior to the adoption of the new recommendations, the Corporation presented the revolving demand loan as long-term debt on the basis that the lender had indicated it was not its intention to demand repayment within one year provided there was no adverse change in the financial position of the Corporation.

The lender classifies the Corporation's revolving production loan facility as a demand loan; however, the lender is not aware at this time of any facts, events, or occurrences, which would cause the lender to demand the loan prior to May 31, 2003 (the next annual review date), provided there is no adverse change in the financial position of the Corporation. This facility is demand in nature and pursuant to the CICA pronouncement is presented as a current liability.

At December 31, 2001 no amount was drawn on this facility.

5. SHARE CAPITAL

(a) Authorized:

Unlimited number of Common Voting Shares without nominal or par value

Unlimited number of First Preference Shares

Unlimited number of Second Preference Shares

The First and Second Preferred Shares may be issued in one or more series and the directors are authorized to fix the number of shares in each series and to determine the designation, rights, privileges, restrictions and conditions attached to the shares of each series.

(b) Issued:

	Number of Common Shares	Amount $
Balance, December 31, 2000	16,024,775	7,313,982
Shares issued on exercise of warrants (Note 5(c))	70,000	42,000
Shares issued on exercise of options (Note 5(d))	75,000	21,750
Shares issued on private placement, net (Note 5(e))	3,205,443	2,713,987
Shares issued on private placement, net (Note 5(f))	12,823,000	2,561,185
Future income tax liability on flow-through share expenditures incurred	–	(1,325,457)
Future income tax benefit on share issue costs	–	73,584
Balance, December 31, 2001	32,198,218	11,401,031
Shares issued on private placement, net (Note 5(g))	24,999,999	7,004,632
Shares issued on private placement, net (Note 5(h))	3,394,462	2,115,471
Shares issued on private placement, net (Note 5(i))	200,000	199,050
Future income tax liability on flow-through share expenditures incurred	–	(782,274)
Future income tax benefit on share issue costs	–	246,644
Balance, December 31, 2002	**60,792,679**	**20,184,554**

(c) On February 15, 2001, a total of 70,000 share purchase warrants were exercised at an exercise price of $0.60 per warrant, for net proceeds of $42,000. As a result, 70,000 common shares of the Corporation were issued to the holders of these warrants.

(d) On June 1, 2001, a total of 75,000 stock options were exercised at an exercise price of $0.29 per share, for net proceeds of $21,750. As a result, 75,000 common shares of the Corporation were issued to the holders of these stock options.

(e) On July 11, 2001, the Corporation issued 3,205,443 flow-through common shares, through a private placement at a price of $0.90 per share for net proceeds of $2,713,987. Pursuant to a flow-through share agreement, the Corporation renounced $2,884,899 of income tax deductions in 2001 to the subscribers of these shares. At December 31, 2002, $2,884,899 had been spent on qualifying expenditures.

(f) On December 14, 2001, the Corporation completed a private placement of 12,823,000 common shares at a price of $0.20 per share for net proceeds of $2,561,185.

(g) On February 14, 2002 the Corporation issued 24,999,999 common shares through a private placement at a price of $0.30 per share for gross proceeds of approximately $7,500,000. Net proceeds were approximately $7,004,632.

(h) On October 31, 2002, the Corporation issued 3,394,462 common shares through a private placement at a price of $0.65 per share for gross proceeds of approximately $2,206,400. Net proceeds were approximately $2,115,471.

(i) On December 19, 2002, the Corporation issued 200,000 flow-through common shares through a private placement at a price of $1.00 per share for net proceeds of $199,050. Pursuant to a flow-through share agreement, the Corporation renounced $200,000 of income tax deductions in 2002 to the subscribers of these shares. At December 31, 2002, $200,000 has been spent on qualifying expenditures.

6. STOCK OPTIONS

A summary of the changes during the year ended December 31, 2002 and the Corporation's outstanding options as at December 31, 2002 is presented below:

	Number	Weighted Average Exercise Price
Outstanding, December 31, 2000	1,306,250	$0.77
Granted	200,000	$0.62
Exercised	(75,000)	$0.29
Repurchased and/or cancelled	(145,000)	$0.37
Outstanding, December 31, 2001	1,286,250	$0.82
Granted	4,123,750	$0.68
Exercised	–	
Repurchased and/or cancelled	(68,750)	$0.63
Outstanding, December 31, 2002	**5,341,250**	**$0.71**

Date of Grant	Number Outstanding at December 31, 2002	Date of Expiry	Exercise Price	Number Exercisable at December 31, 2002
June 13, 2000	37,500	August 1, 2005	$0.40	25,000
September 20, 2000	905,000	September 20, 2005	$0.85	603,333
October 30, 2000	125,000	October 30, 2005	$1.04	83,333
May 4, 2001	200,000	May 4, 2006	$0.62	66,667
March 7, 2002 to August 21, 2002	2,605,000	March 7, 2007 to August 21, 2007	$0.64 to $0.66	–
September 30, 2002 to December 14, 2002	1,468,750	September 30, 2007 to December 14, 2007	$0.70 to $0.76	–
	5,341,250			778,333

Diluted calculations include additional common shares for the dilutive impact of the stock options outstanding at December 31, 2002. In determining the diluted earnings per share, the Corporation determined that 237,500 (2001 - Nil) stock options had a dilutive impact of increasing the weighted average number of common shares by 17,461 (2001 - Nil). This amount has no material impact on the earnings per share calculation or the weighted average number of shares.

7. STOCK-BASED COMPENSATION AND OTHER STOCK BASED PAYMENTS

Effective January 1, 2002, the Corporation adopted the new recommendations of the Canadian Institute of Chartered Accountants with respect to stock-based compensation. These recommendations are required, to be applied on a prospective basis for stock options granted on or after January 1, 2002. The Corporation accounts for its stock-based compensation plans using intrinsic values rather than the fair value method. The exercise price of all stock options granted to employees and directors by the Corporation are at the current market price of the common shares at the time of grant and therefore, no compensation expense is recognized in the consolidated financial statements.

If the fair value method had been used, the Corporation's net earnings per share on a pro forma basis would approximate the following:

($000's, except per share)	2002
Compensation expense (fair value method)	287
Net earnings	
As reported (intrinsic values)	2,597
Pro forma (fair value method)	2,310
Net earnings per common share	
Basic and diluted	
As reported (intrinsic values)	$0.047
Pro forma (fair value method)	$0.042

The fair value of each option granted after January 1, 2002 was determined on the date of the grant using the Black-Scholes option-pricing model. The weighted average assumptions used in calculating the fair values are set forth below:

	2002
Risk free interest rate	5.05%
Expected maturity (years)	5.0
Expected volatility	63.43%
Dividend per share	$0.00

8. INCOME AND OTHER TAXES

As at December 31, 2002, the Corporation has exploration, development, acquisition and facility costs available for deduction against future taxable income of approximately $23,308,000 (2001 - $8,134,616). In addition, at December 31, 2002, the Corporation has non-capital losses carried forward for income tax purposes of approximately $83,000 (2001 - $3,028,000). These non-capital losses are also available for deduction against taxable income in future years.

The provision for income taxes differs from the result, which would be obtained by applying the combined Canadian federal and provincial income tax rate of approximately 42% and 42.21% for the current and prior year respectively, to the earnings (loss) before taxes. The difference results from the following items:

	2002 $	2001 $
Computed expected income tax provision (recovery)	**1,091,029**	(4,326,758)
Increase (decrease) in taxes resulting from:		
Non-deductible crown charges	**715,259**	44,213
Non-deductible expenses	**6,300**	1,355
Resource allowance	**(526,618)**	36,696
Alberta Royalty Tax Credits	**(26,380)**	(3,378)
Recognized benefit of non-capital losses and other items	**(1,795,220)**	-
Unrecognized benefit of non-capital losses and other items	**-**	2,995,999
Future income tax recovery	**(535,630)**	(1,251,873)

The Corporation's current tax expense for the year ended December 31, 2002 was $54,776 (2001 - $67,200). The Corporation has paid $28,776 (2001 - $67,200) in current taxes relating to Part XII.6 tax. This tax is calculated based upon the month in which resource expenditures are incurred that were previously renounced by the Corporation under the terms of a flow-through share agreement. The remaining $26,000 (2001 - Nil) relates to the Large Corporations Tax for the 2002 taxation year.

9. COMMITMENTS AND CONTINGENCIES

The Corporation is committed under one operating lease for its premises with the following aggregate minimum lease payments to the expiration of the lease on December 30, 2004.

	$
2003	216,000
2004	216,000
	432,000

The Corporation has sold forward 100 bbls/d of heavy oil from January 1, 2003 to December 31, 2003 based on a price of Cdn $24.87 for LLB (Light Lloyld Blend) at Hardisty.

10. SUPPLEMENTARY CASH FLOW INFORMATION

Interest paid on a cash basis for the current year was $212,461 (2001 - $21,016). Current taxes paid on a cash basis for the current year were $54,776 (2001 - $67,200) (see Note 8).

The following table details the components of non-cash working capital provided by (used in) operations.

	2002 $	2001 $
Accounts receivable	**(1,946,711)**	10,749
Marketable securities	**–**	5,623
Deposits and prepaid expenses	**258,659**	28,411
Accounts payable and accrued liabilities	**1,964,863**	785,216
Current portion of long-term debt	**–**	(39,959)
	276,811	790,040

11. SUBSEQUENT EVENTS

The Corporation has entered into two separate transactions whereby it has agreed to sell certain of its heavy oil properties for gross proceeds of $2,500,000, before adjustments. Both transactions were closed on February 28, 2003.

12. COMPARATIVE FIGURES

Certain comparative figures have been restated to conform to the current year's presentation.

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OFFICERS

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Vice President, Operations

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BANKERS

Alberta Treasury Branches
Calgary, Alberta

TRANSFER AGENTS

Computershare Investor Services Inc.
Calgary, Alberta

STOCK EXCHANGE LISTING

Toronto Stock Exchange (TSX)
Symbol: **CAZ**

ABBREVIATIONS

API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
bbl	barrels
bbls/d	barrels per day
mbbl	thousands of barrels
boe	barrels of oil equivalent (6mcf = 1 boe)
boe/d	barrels of oil equivalent per day
mboe	thousands of boe
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
TSX	Toronto Stock Exchange
NGL's	natural gas liquids
CAZ	Case Resources Inc.
WTI	West Texas Intermediate Crude Oil
*	Conversions to barrels of oil equivalent are calculated on the basis of 6 mcf being equivalent to 1 barrel of oil.

2002 ANNUAL REPORT

CASE

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